Hydraulic Fracturing 101:

What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor, and Engineer Should Know About Hydraulic Fracturing Risk

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The use of horizontal wells and hydraulic fracturing is so effective that it has been called "disruptive." That is, it threatens the profitability and continued development of other energy sources, such as wind and solar, because it is much less expensive and far more reliable. Not only that, but compared with coal, natural gas produces only half the carbon dioxide and almost no sulfur, nitrous oxides, or mercury.

Those demonstrable benefits over both traditional and alternative energy draw monetary and political attacks. Some university and media reports have focused on two main environmental concerns about using hydraulic fracturing to recover shale gas:

- Groundwater and/or surface-water contamination by methane or chemicals
- Escape of methane gas to the atmosphere

These risks come from well construction, transportation of chemicals and fluids to the well site, and operation of the wells and the gas-transport system. This paper is an abbreviated analysis of a larger document on factural information about the purported risks of hydraulic fracturing:

1. Deep-well hydraulic fracturing does not travel through the rock far enough to harm fresh-water supplies. Thousands of field-monitoring tests and millions of fracturing jobs have confirmed this point.

2. In the deep, properly constructed wells that produce most US shale gas, the chance of even minor water contamination from fracturing chemicals is less than one event in a million fracture treatments, based on statistical analysis. When compared with the frequency of pollution from chemical dumps, acid mine drainage, general manufacturing, oil refining, and other energy- or product-producing activities, natural gas from conventional and unconventional sources generates more energy with the least impact and fewest problems.

3. Even as underground fractures grow (mostly outward with limited upward and downward growth), the total fracture extent remains thousands of feet below the deepest fresh water sands. The height of any fracture is limited by rock stresses, leakage of fracturing fluids within the target fracturing zone, and the hundreds of natural rock barriers that border the shale zone. Typical fracture height is 100 to 300 ft and separation between the top of the fracture and the deepest fresh water sands ranges from 3000 to over 5000 ft.

4. Water contamination due to spilled industrial chemicals occurs rarely and even less so for fracturing chemicals and comes exclusively from careless road transport, on-site storage and surface mixing, or well construction. These failings can be addressed successfully with existing technology and effective regulations. It is interesting to note that the states with the fewest problems are those with strong state regulations. Appropriate regulations already exist in most producing states and work very effectively to protect the environment.

5. In the deep wells typical of shale gas, no documented case of any chemical contamination from hydraulic fracturing has been found.

6. The impact of chemical spills and leaks is low and can be decreased further by improvements in transport containment, storage methods, and chemicals.

7. Although hydraulic fracturing does not increase the presence of methane in water wells, poor well construction and natural seepage can create methane movement. Eliminating this potential problem requires the proper cement isolation of any methane-producing section of rock. This prevents the wellbore from conducting the methane that is sometimes found in shallow coals or thin shales into fresh-water zones or wells. High-pressure air drilling also may play a role in stirring up sediment and activating natural bacteria that produce odors, color, and foul tastes in shallow fresh-water zones. This potential problem can be addressed with changes in drilling techniques.

Since widespread shale development began a few years ago, there has been a growing furor about hydraulic fracturing to recover shale gas. The concern grows from three sources:

- Lack of chemical disclosure by the drilling companies
- Inadequate pre-2011 well-construction regulations in some states
- Widespread misinformation, sometimes from poor communication and some spurred by the threat of cheap natural gas to the development or profitability of other energy sources

However, some problems with wells that are to be fractured have emerged and require improved well design for certain geologic areas. Early regulation oversight and control have been challenged in some areas, particularly those states not familiar with large-scale oil and gas operations. Fortunately, state regulations can be reviewed and changed quickly through review by other state regulators and specialty groups with knowledge of local conditions. STRONGER (State Review of Oil and Gas Regulations) is particularly effective with its state-by-state review of regulations by a coalition of state regulators, industry and public interest groups has been particularly effective.

Nothing New Under the Ground

Hydraulic fracturing and horizontal wells are not new tools for the oil and gas industry. The first fracturing experiment took place in 1947, and the process was commercial by 1950. The first horizontal well was envisioned in the 1930s, and horizontal wells were common by the late 1970s. Millions of fractures have been pumped, and tens of thousands of horizontal wells have been drilled worldwide during the past 60 years.

The recovery of shale gas is not new, either—especially from the Devonian shales in western Pennsylvania. This is, after all, where Edwin Drake, exploring the area's natural seeps of oil and gas, drilled the first US oil well in 1859—to a grand total of 69 ft deep. In fact, native North Americans gathered oil and tar from natural seeps more than

Effective Well Construction

Well construction problems are fairly rare, with only a small percentage of wells repairing cement or casing before they can be fractured or even drilled beyond their test depth. The American Petroleum Institute recommends practices for well construction, and many states set specific requirements based on local geological conditions. Many energy companies set even higher standards based on their experience in local areas. It is the local geologic conditions that most heavily influence well design.

Good engineering creates a well-specific design that will control any fluid, any reservoir, and any fracturing pressure, and that will last much longer than it will take to produce the oil and gas. The goal of well design is to:

- Protect the surrounding nonhydrocarbon zones, including freshwater aquifers
- Protect the well from formation problems external to the well, such as corrosive gas or saltwater
- Protect the well from the forces of Earth movement

Effective well designs use multiple barriers of pipe as well as cement to isolate the well. They are designed so that, if one component fails, the inner pipe may collapse but the outer, protective pipes will remain in place, isolating the well.

For most wells, the outer pipe (casing) extends from ground level to several hundred feet below the deepest freshwater aquifers, ideally into a sealing-rock barrier. After they place the pipe, workers pump specially formulated cement to the bottom of the casing string and continue pumping, displacing the cement so it moves upward around the exterior of the pipe. The cement holds the casing in place and isolates the well from the surrounding formations. When properly formulated and placed, cement creates an extraordinarily long-lived seal.

Poor cement jobs are influenced by three main problems:

1. Failure to bring the cement top high enough in the annulus. Bringing the cement top higher in the wellbore will solve many issues, but cementing the full casing length from bottom to top is not always needed and cannot always be accomplished in a single application due to risk of fracturing formations with the pressure of a full column of cement that is nearly twice the weight of water. A full column of cement would exert pressures on the rock that are high enough to fracture the rock, which would lower the final top of cement in the annulus and damage formations. Lighter weight cement and/or more expensive two-stage cement job are options, but the key is covering all producing zones with cement that effectively seals the intervals. The amount of cement required is set by local conditions of gas-charged formation exposure and formation pressures.

Running two strings of pipe instead of a single long string, is another method for applying a step-wise barrier, although the cost of larger surface pipe, an extra steel casing string, and the time required to run and set the extra string make this option expensive. The best barriers are those that can be confirmed by pressure testing and logging and can easily be rechecked as needed.

2. Failure to get cement around the casing and completely displace the mud. The cement seal depends on filling the annulus with uncontaminated cement and bonding to both the steel casing and the wall of the drilled hole. The casing must allow the cementing preflush to flow around the entire circumference of the casing, displacing the mud and cleaning the mud film off the pipe and the formation. Reasons for failures include lack of centralizers in the cemented section, poorly designed preflush (the main cleaning step), and use of insufficient cement.

3. Gas migration in the cement. During drilling and completion and before the final well completion steps, the mud or other fluids in the hole must offset the reservoir fluid pressures with hydrostatic pressure to keep the reservoir fluid from flowing. When cement displaces the mud from the annulus, the liquid cement easily keeps the gas contained in the formation, but, as the cement begins to gel and progresses towards a hard solid barrier, the action of bonding to the formation and pipe wall reduces the hydrostatic pressure that the cement can exert. During this time, small amounts of gas have been shown to enter the wellbore and create small, sometimes linked channels within the setting cement. This problem has been described for over 20 years but some operators do not realize the hazard that the gas produces if it migrates sufficiently up the cement column and establishes linked channels through the cement. The volume of gas moving through these leak paths is small, but the leakage is a problem that must be avoided or annular pressures can result.

1,500 years ago. And the first shale gas well was drilled in Fredonia, New York, in 1821. Concentrated shale fracturing research was funded by a US Department of Energy grant in the 1970s.

Even with a early grant from DOE, shale gas only became economically attractive in 2001 through pioneering efforts of Mitchell Energy and others as they adapted earlier technologies to fit the specific demands of shales. Shales are definitely a technology-driven accomplishment, with gas recoveries increasing from one or two percent of original gas in place (OGIP) to over 30 to 40% by 2011. Even as the successful production of so much natural gas has suppressed prices, technological advances have made shale gas the darling of the oil field.

Because of shale gas, the US has transformed itself from an importer of natural gas to total energy independence in natural gas. In fact, now there is a surplus. During the next 20 to 25 years, shale gas will account for as much as 35% of all natural gas produced in the US. If you add to these figures other forms of "unconventional" gas, hydraulic fracturing will enable production of the majority of all natural gas supplies in the US (EIA, Energy Outlook, 2012).

The oldest modern shale gas wells are only about 13 years old. Yet many of these wells already have produced more gas than initially estimated. Shale-specific fracturing technology adaptation has increased production rates dramatically and is reversing the rapid decline witnessed in many early shale gas wells. The bottom line is that shale gas has increased gas reserves far beyond initial hopes. Today's advanced shale gas technologies help engineers place wells in the most productive areas. These technologies are enhancing the economics of shale, even with a surplus of gas available.

Extensive Research Backs Shale Gas Technology

As shale technology has developed during the past 30 years, more than 550 technical papers have investigated it. Horizontal drilling has been the subject of more than 3,000 technical papers. These papers have been presented publicly to a worldwide review audience of 100,000 experienced energy industry scientists and engineers. Just since 2008, technical papers about shale gas have been produced by more than 70 universities; four US government labs; more than a dozen agencies at the state, federal, and international level; and approximately 100 energy industry companies. A 2010 paper, Thirty Years of Gas Shale Fracturing: What Have We Learned? reviewed more than 270 literature sources and documented a steady progression of technological advances.

Critics of hydraulic fracturing say that some fracturing jobs have contaminated ground and surface waters. Engineers insist that not one deep-well fracture has ever contaminated groundwater. They cannot both be right. But a little explanation goes a long way.

Part of the problem is how each group defines fracturing. For critics, fracturing has come to represent nearly every phase of the well-development cycle—from the exploration that precedes drilling all the way through to gas production. For engineers, fracturing is a portion of this process: a means of using fluids, under pressure, to open, enlarge, and stabilize cracks in deep, gas-producing rocks far below the Earth's surface.

Concern About Chemicals

One of the biggest drivers of public and investor concern in the fracturing debate has been the identity and composition of chemicals used in all phases of well development. Although there is virtually zero chance of fracturing into a fresh-water supply from a deep well (less than 1 in 1,000,000), there is valid concern about even low incident potential events (in the range of 1-in-10,000 to 1-in-100,000), such as spills, leaks, cement channels, and traffic accidents that could contaminate small amounts of either surface or subsurface water.

Although the volumes lost in these "non-fracturing" events are typically small, reducing the chemical volumes and eliminating dangerous chemicals is a responsible way forward. "Green" chemical development is starting in the petroleum industry and elsewhere. Given the concerns of the public, the best approach is to respond to the questions being asked and help drive the development of better chemical additive approaches and safer handling practices. Fortunately, industry vendors have responded, driving down the toxicity of most chemicals, eliminating others, and providing choices of safe, biodegradable products in nearly all areas. The industry will be watched closely to see how they accept and use these materials. Fortunately, the new products are not only safer, they are also cost-effective.

Dangerous chemicals have not always been widely recognized in any industry. Recent work in identifying carcinogens, endocrine (genetic) disruptors, toxins, byproducts, and bioaccumable materials is progressing. Simplifying and reducing chemical additives along with reduction to total environmental impacts are seen as a large part of the social license to operate in the world.

In a properly designed and executed well development plan, the toxic chemicals, principally low-dose biocides, can be replaced with materials that are effective but offer biodegradation ability and are often used in municipal drinking water preparation. The most commonly used biocides are the same materials used in hospitals and food preparation, with relatively low concentrations but a total volume that can be similar to the volumes stored for small manufacturing facilities. One of the most pressing issues in the oil and gas industry is to examine and adopt other technologies, chemical and non-chemical, to replace as many non-green chemicals as possible.

There are generally one to five purchased chemicals used in a slickwater fracture job (**Table 1**). However, other trace chemicals used in product preparation, as carriers and impurities, may be found in some fracturing fluids. Even the fresh-water supplies used in fracturing often contain a group of common minerals and metal ions, plus several "tag-along" trace chemicals, byproducts

TABLE 1—COMMON ADDITIVES USED IN SLICKWATER FRACTURING IN SHALES			
Slickwater Fracture Additives	Composition	Percentage of shale fractures that use this additive. (This is not concentration.)	Alternate use
Friction Reducer	Polyacrylamide	Near 100% of all fractures use this additive	Adsorbent in baby diapers, flocculent in drinking water preparation
Biocide	Glutaraldehyde	80% (decreasing)	Medical disinfectant
Alternate Biocide	Ozone, chlorine dioxide UV	20% (increasing)	Disinfectant in municipal water supplies
Scale Inhibitor	Phosphonate and polymers	10 to 25% of all fractures use this additive	Detergents and medical treatment for bone problems
Surfactant	Various	10 to 25% of all fractures use this additive	Dish soaps, cleaners

of manufacturing, agriculture, or trace pollutants in even drinking water, that have nothing to do with the petroleum industry. These materials are usually at trace concentrations.

Detailed laboratory analysis on surface waters from ponds in agricultural areas detail a water history of traces of herbicides, fungicides, and pesticides common to agriculture as well as chemicals that could have arrived only through airborne pollution from cities and industries upstream of the sample point. Nearly all of these chemicals are at the limit of analytical detection. Many of the raw, fresh-water sources for fracturing fluids are the same or similar to those used by municipal sources that end up as drinking water.

The EPA lists common sources of drinking water pollution from human activities as, "Human activities: bacteria, and nitrates (human and animal wastes—septic tanks and large farms); heavy metals (mining construction, older fruit orchards); fertilizers and pesticides (anywhere crops or lawns are maintained); industrial products and wastes (local factories, industrial plants, gas stations, dry cleaners, leaking underground storage tanks, landfills, and waste dumps); household wastes (cleaning solvents, used motor oil, paint, paint thinner); lead and copper (household plumbing materials); and water treatment chemicals (wastewater treatment plants). Where does the upstream oil and gas industry fit on this pollution source list? Surprisingly, because of strict disposal and injection control of UIC-II wells, there have have been only a few reported or tested problems. Even then, this can be made safer with safer, more biodegradable materials.

Laws that have been enforced in western producing states for decades prevent surface discharge of most produced water and all fracturing returns. Some, high purity coalbed methane produced waters are allowed by exception for agriculture uses, with monitoring of minerals and chemicals.

Is There a Danger from Fracturing Fluid Left Downhole?

Fluid backflow is the activity of cleaning up or flowing the well after fracturing to recover part of the fracturing fluid and initiate the gas production. Recovery of fluid depends on the formation and how much water that the shale formation adsorbs and absorbs into its structure. The amount of water in a formation, or its percentage of water saturation, depends on the composition and form of the minerals such as clays at the microscopic level. If the formation minerals do not have sufficient water in their structure, they will trap and hold water from any available source until the minerals reach an irreducible water level. Water trapped in this manner may dry out again over geologic time through dry gas evaporation of the bound water, but is not likely to move during years of production. Water removed by dehydration will not transport chemicals, which will remain trapped in the rock.

Recent work in optimizing fracturing fluid backflow has determined that some percentage of the water from the fracturing job that is not recovered may be assisting production by slightly enlarging the mineral structures that adsorb the water. These water-altered minerals may be responsible for propping open small fractures and fissures, increasing the capacity of the formation to flow. Several companies are experimenting with the concept of shutting wells in for extended times after fracturing and before flowback, allowing more leakoff and less total returns. Initial unpublished results appear to be very good with lower decline rates noted when wells are placed on production.

Chemical additives such as surfactants and other surface active agents (soaps, cleaners, foamers, emulsion breakers and other beneficial treating chemicals) are also lost to the formation through adsorption onto mineral surfaces and come out extremely slowly, if at all. These fluids pose little or no risk to the environment since they cannot

Frequently Asked Questions

If the fracturing process is thousands of feet beneath the water table, then why is methane showing up in residential water wells?
Methane is a contaminant in many water wells, and its causes are both natural and human-generated. If oil and gas wells are poorly constructed, they may allow methane from shallow formations, such as coals and thin shales, to migrate into water supplies. This is a common cause of contamination in northwestern Pennsylvania, where century-old wells and natural seeps are often at about the same depth as nearby water wells. Proper well construction, with sufficient cement to isolate the drilled hole, prevents shale gas wells from creating migration paths for methane.

The vast majority of oil and gas from shale does not seep to the surface. In fact, it is difficult to produce. What keeps it in the ground for millions of years?
In nearly all areas, oil and gas is sealed in place by rock that is virtually impermeable, such as high-clay-content shale (vs. productive shales, which contain natural fractures and microfissures). These durable natural barriers, which have withstood tectonic forces and Earth movements for millions of years, also prevent migration of the fluids used for hydraulic fracturing. The containment capability of these rock seals is proved by the fact that oil, gas, and saltwater are still in place after millions of years: The lower density gas and oil have not migrated upward through the heavier saltwater found in shallower zones. This is further documented by fracture-monitoring methods such as microseismic monitoring, which detects and locates the sounds of fracturing. Oil companies use these techniques to monitor the first few wells in an area so they can optimize their fracturing design.

What about radioactivity from fracturing?
Our planet and everything on it is radioactive and has been that way since it was formed. Every piece of rock or dissolved soluble ion has a radioactive signature, including the purest drinking water and the dirtiest mine waste.

Fracture flowback waters may have a radioactive signature, picked up from the rocks that the fluid passes through. In most areas, including shales, the radioactive levels of frac-fluid flowback are far below the background limit set by US government agencies. Because the radioactivity in a formation is reasonably consistent, initial monitoring of flowback is usually sufficient to assess any risk. However, disposal companies measure radioactivity a second time, before they dispose of the fluids. The radioactivity in shale may be slightly higher than that of other rocks due to higher organic content, but most formations will return flowback fluids that are well below the safety threshold.

What stops the upward growth of hydraulic fractures?
Fractures usually grow upward until they contact a rock of different structure, texture, or strength. These "seal" or fracture-barrier rocks stop the fracture's upward or downward growth. They are very common in every set of rocks where shale occurs.

The loss of fracture fluid, called leakoff, also stops fracture growth. During leakoff, part of the fracturing fluid seeps into permeable parts of the gas-bearing formation below the cap rock, decreasing the amount of fracture fluid and fracture pressure.

What kinds of chemicals are used in fracturing?
In a properly designed and executed fracturing plan, the few toxic chemicals—principally low-dose biocides—can be replaced with materials that are effective, but that will biodegrade or be completely consumed in their destruction of biological organisms. Preferred biocides and nonchemical approaches are the same ones used in municipal drinking water. Other common fracturing biocides are used in hospitals and food preparation. These "greener" chemicals and nonchemical approaches are catching on quickly with technology-savvy operators.

From nearly every scientifically run analysis, the actual act of fracturing does not contaminate water supplies. A US city drinking water evaluation from the Environmental Working Group (which is decidedly anti-oil and gas) notes that three of its top 10 US municipalities with superior drinking water are in Texas, including Fort Worth—the middle of the Barnett Shale, the site of intensive hydraulic fracturing.

Are produced water and oilfield wastes exempt from federal hazardous waste regulations?
No, although they are not considered highly toxic under federal regulations. After a 10-year study, the US Environmental Protection Agency exempted oilfield wastes from RCRA Subtitle C regulations. They fall, instead, under Subtitle D and other federal and/or state waste regulations.

Most oilfield produced water, including fracture flowback, is reused repeatedly at the well for pressure maintenance.

Does the water used in hydraulic fracturing contribute to water shortages?
It can in arid areas. In the Horn River gas shale of Canada, Apache uses a closed-loop saltwater system, instead of

fresh water, for fracture fluids. In other areas, the company is likewise developing alternate water sources, such as saltwater from oil and gas producing formations.

The volumes of water required for fracturing are low compared with agricultural, municipal, recreational, and other industrial use. However, we can reduce pressure on local fresh-water supplies by using produced and natural high-salinity waters that are not suited for use as drinking water.

Does fracturing cause damaging earthquakes?

No. Fracturing, in very rare cases, may generate a very low strength seismic tremor, measurable only by sensitive instruments within a few thousand feet of the pay zone. These fracture events are a million to a billion times less strength than the smallest damaging producing quake. But fracturing does not penetrate deep enough to reach major faults and tectonically active plate boundaries, which are 2 miles to more than 5 miles beneath the Earth's crust

What about emissions from the production and burning of natural gas?

The production and burning of natural gas creates two kinds of emissions: direct (from methane venting, fugitive emissions, and combustion) and indirect (from trucks, pumpers, and processing equipment that burn diesel or other fuels). Using pad operations and transferring water via pipeline can reduce truck traffic, as well as ground disturbances. With pad-oriented development, operators can access about 6,000 acres of reservoir from a single 6-acre pad area. Pad developments also offer economies of scale that encourage the use of low-pressure methane-recovery units. These units sharply reduce the need for methane venting and thereby reduce direct emissions of methane.

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move, migrate, or even release from the formation at higher than part-per-million levels. Trapped water cannot move from the clay or migrate upward because of the same seal rocks at the top of the reservoirs that hold the gas and oil in place. These seals have sealed oil and gas in place for millions of years resisting earthquakes and earth movements over geologic time. Reduction of chemicals and substitution of "greener" chemicals can reduce the small risk even further.

The first fluids to flow from the well are usually the last fluids injected (i.e., the water base of the fracturing fluid). Chemical content of this backflow is dominated by mixing with reservoir fluids. Salt content in the returning fracturing fluid may change with the mixing of these waters. First gas may be seen from 2 days to 20 days after fracturing, depending on back pressures, shale system permeability, and flowback design intent.

As gas begins to flow, the rate of water recovery falls rapidly. This will vary slightly between areas, but the general behavior is similar. This rapid drop in water rates at the first show of gas makes it easy to flow the large early volumes of returning water to tanks for the first few days and then switch to through-the-separator flow with much lower water rates as the gas production starts (**Fig. 1**). Interpretation of early time behavior of gas flow is often confused by decisions to hold a back pressure on the system to flatten decline rates and increase recovery, but may also be influenced by pipeline curtailments or high pipeline pressures or gathering system interruptions.

Conclusions

Drawing conclusions from this study involved an initial separation of well construction issues (where a company's design philosophy in a local geologic area can be a major risk differentiator) from the specific rock fracturing risk (where every company faces nearly identical risks). Well construction, being a separate risk entity, is not considered here

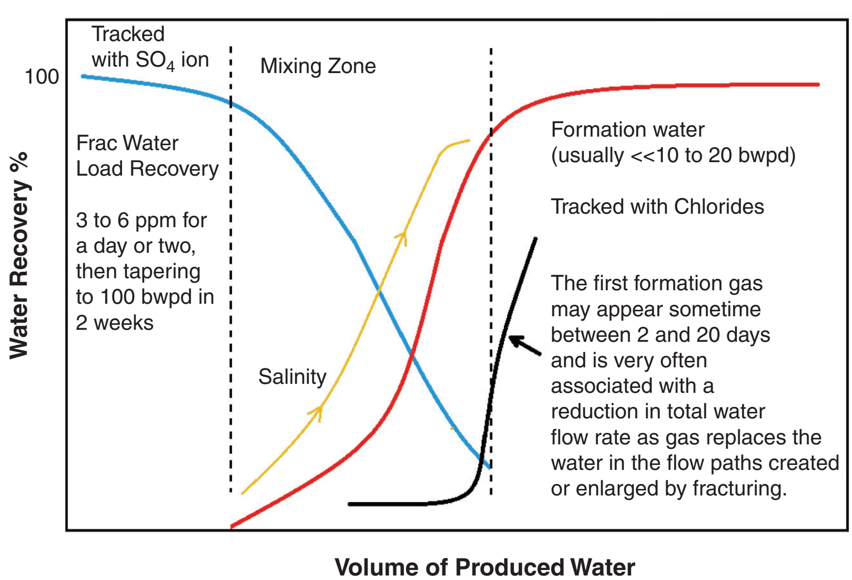

Fig. 1—Approximation of events in post-fracture flow (flowback).

but several challenges are covered in the risk evaluation.

1. The primary conclusion that fracture treatments do not penetrate fresh-water supplies in a properly constructed wellbore, is derived from a preponderance of evidence from monitoring fracture growth (microseismic, tracers, logging, tilt meters, pressure tests); absence of primary fracturing chemical components outside the pay zone; limitations placed on fracture growth by natural seals, fracture tracers, fracture barriers, leakoff, and a 60-year history documenting fracture containment in numerous geologic settings. However, this conclusion is on a narrow topic of fracture pumping, and is not an innocent verdict on the entire well development process. There is no technique so perfect that improvments cannot be made.

2. The potential for even a small amount of chemical contamination of underground or surface sources of fresh water from the specific act of fracturing, applied in adequately constructed wells with pay zone depth of greater than 2,000 ft, is arguably less than one in a million fractures because of the self-limiting nature of fracturing leakoff and the numerous fracture barriers found in every deeper formation sequence.

3. Height of fracture growth in deep wells is usually a few hundred feet above the targeted hydrocarbon zone but thousands of feet below the deepest fresh-water sands. This has been documented by downhole microseismic, tilt meters, tracers, logging, and other methods.

4. The potential for chemical contamination of underground or surface sources of fresh water during all phases of well development comes exclusively from road transport of fracturing components or fuel, on-site storage, surface mixing of fluid components, and failures in well architecture caused by inadequate well construction methods, usually centered on inadequate cementing operations. Cementing highlights the challenges that demonstrate different well and cement designs for different areas.

5. From construction of a dual risk analysis, featuring non-technical vs. technical application of fracturing, there is sufficient confidence that frequency of spills or leaks from higher risk events (transport, storage, and well construction) can be sharply reduced by more attention to the root cause of these spill or leak events.

6. With proper well construction, there was no documented case located of fracturing chemical migration to a fresh-water aquifer or to the surface from a zone deeper than 2,000 ft. A few cases of suspected contamination by chemicals in shallower zones are known, with many, if not all, linked to poor isolation of the well during the well construction phase and not to fracture penetration.

7. Although the impact of spill and leak events is generally low, they can be decreased further by reducing number, amount (concentration and/or activity), toxicity and environmental permanence of chemicals used in fracturing. Chemical rating systems that focus on these issues should be a part of the planning for any fracture treatment.

8. For targeted hydrocarbon pays of less than 2,000 ft depth, state regulators with knowledge of local geological systems may need to set specific limits on well depth, fracture volume, rate, or type of fluid. The special case of fracturing in very shallow wells, particularly those at depths less than about 2,000 ft or with fresh water within 1,000 ft of the hydrocarbon containing formation, is cause for concern, and additional evaluations of geology, fracture rates, and volumes are required.

9. Methane presence is commonly recorded in water wells across the country and may predate any drilling or fracturing in the area. These methane occurrences may be biogenic or thermogenic methane and can be widely linked to natural seeps of methane gas, both continuous and episodic. Methane may increase during a water well's life as water is produced, as a result of liberating methane that was adsorbed in and onto organic materials in the sediments. This type of methane increase is particularly active in fresh water containing coal seams and high clay content shales. As the fresh-water aquifer levels are drawn down, the methane adsorbed on the organics will desorb and overall methane content in the water well will increase. Avoiding coal seams and high organic source rocks by proper cement isolation in the fresh-water wells is required to minimize this problem.

10. Potential for increasing methane in nearby water wells from oil and gas well development activities can be increased by poor cement isolation and inadequate cement level in surface or production strings.

11. Transparency is, by necessity, a two-way street and needs to be addressed by all parties in the discussion. The oil and gas industry needs to explain its processes, identify chemicals to the public, and improve the well development process where needed. The oil and gas industry must work to replace the few toxic chemicals it uses (primarily biocides and a few surfactants) with chemicals that are low impact and biodegradable; perhaps a similar approach to that used successfully in the North Sea. The public needs to understand what the industry is doing and be able to engage in a local and national forum with a solid base of understanding. Disclosure by the popular media of its political and technology bias (and lobbying support) would certainly help the discussion.

12. High-quality research papers using accepted scientific methods and without overt or covert political objectives and/or corporate influence do not appear to have received equal attention or air time in a media driven by sound bites. This must change if decisions are to be based on facts. **JPT**

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